INTRODUCTION

The Board is being asked to expedite an approval for leave to construct a replacement pipe for the St. Laurent pipeline system. While not new, the pipeline is not of the vintage of the recently approved for replacement Windsor and London lines. The onus is on EGI to demonstrate their proposed replacement is prudent.

EGI has attempted to provide a history of incidents and inspections to try to demonstrate that the pipe is in poor condition and is urgently in need of replacement to obviate catastrophic failure with huge cost consequences. FRPO has reviewed this history and respectfully submits that EGI is attempting to create an illusion of a pipe in poor condition. Examination of the evidence provides a much different perspective. In fact, their own internal Asset Health index reflects a pipe that will not come into failing health for decades.

Detailed in our submission are our experienced observations, analysis and understanding that contributes to our informed recommendation that this pipeline requires continued maintenance and inspection and NOT replacement at this time. Respectfully, we urge the Board to deny the request approvals and instead to order EGI to perform enhanced inline inspection and maintenance and report findings as part of its rebasing application for the 2024 test year.

EVIDENCE OF PIPELINE HISTORY DOES NOT REPRESENT FAILING CONDITION

In EGI's pre-filed evidence,[1] the company provides a chronology of events describing inspections and incidents that support their assertion that the pipe should be replaced. The referenced evidence concludes with:

> *As indicated in the AMP, the features described above are all characteristics of vintage steel mains. These features provide an indication of degradation of the pipeline and that the St Laurent Pipeline is reaching the end of its safe and reliable service life and should be replaced.*

This section of evidence is followed by Options Considered[2] which opens with:

> *Faced with a vintage steel pipeline with known (and potentially unknown) integrity issues, Enbridge Gas had to determine how to address those integrity issues.*

However, this chronology of events does not withstand scrutiny with closer examination as most of the evidence of inspections/incidents and related discovery inform that the

[1] Exhibit B, Tab 1, Schedule 1, pages 14-34 plus Referenced Attachments
[2] Exhibit B, Tab 1, Schedule 1, pages 35-48

features and issues described have been resolved or addressed in an appropriate manner. In the following submissions, we provide a different perspective on the evidenced chronology integrity issues. Due to an inability to get information from the company, we cannot provide definitive comment on all aspects of the company's asserted integrity concerns but expect the Board will be assisting by seeing an experienced viewpoint.

Railway Crossing Pipe is Not Representative of Pipeline Condition

EGI's first example of an integrity concern is presented in the section entitled *2006 GPRIP* which describes their use of ground penetrating radar technology to identify potential corrosion defects.[3] The badly corroded pipe was replaced so it is no longer an issue related to the current condition of the pipe.[4] The last paragraph of this section concludes with:

> *Due to the vintage of the St. Laurent Pipeline Enbridge Gas expects there are other segments of the gas main that exhibit similar pitting/corrosion, due to, for example, field applied coatings or latent third party damage.*

We respectfully submit that this statement is inaccurate, at best; misleading at worst. This statement makes it sound like the type of corrosion found in this location would be expected on other sections of the St. Laurent pipeline, but that is not the case. We attempted to demonstrate this conclusion with the witness panel at the technical conference to assist the Board in understanding the uniqueness of this area of corrosion. However, our line of questions and requests were refused.[5]

To assist the Board, we provide the following in support of our conclusion: the section of pipe discovered just north of the only railway crossing of the pipeline.[6] A read of the inspection repair report provides evidence that the significant corrosion is a result of cathodic protection shielding by the casing. The casing is a larger diameter pipe into which the pipeline carrying the gas ("carrier pipe") is inserted through.

> *A type of facility widely used at pipeline crossings is a protective casing, which is a pipe of larger diameter installed under the railroad or highway between right-of-way boundaries either by boring, jacking or open-cut methods of construction. Then the carrier pipe is threaded through the casing and is thereby protected from overburden earth load and static and impact traffic loads.* [7]

[3] Exhibit B, Tab 1, Schedule 1, pages 15-17 plus Attachments 1 & 2
[4] Transcript, Volume 1, March 4, 2022, page 16, line 26 to page 17, line 6
[5] Transcript, Volume 1, March 4, 2022, pages 11-15, 26-27
[6] Exhibit B, Tab 1, Schedule 1, page 16, Figure 4
[7] "Pipeline Crossings Under Railroads and Highways". Mervin Spangler. Journal American Water Works Association Vol. 56, No. 8 (August 1964), page 1029 https://www.jstor.org/stable/41264266

The original design of the casing system was to protect the pipe from loading associated with heavy railcars, as in this case, and from risk of damaging the protective pipeline coating while being installed under the railways.

> *For buried or submerged piping, an external protective coating is the first line of defense against corrosion. Its primary function is to physically isolate a reactive material, such as steel, from the electrolyte, such as the soil surrounding it, thus eliminating opportunities for corrosion to occur. Properly applied coatings also help to reduce cathodic protection current requirements and improve current distribution as less metal is exposed to the electrolyte.*[8]

However, the integrity of pipeline coatings can be compromised during installation or subsequent stresses in the pipeline environment. As a result, pipeline companies apply additional cathodic protection.

> *Corrosion of underground structures such as pipelines is controlled by the use of protective coatings and maintaining adequate levels of cathodic protection (CP). Coating acts as a physical and dielectric (low- or non-conductive) barrier. The protective coating acts as the primary or first line of defense against corrosion. However, no coating system is perfect. To protect the pipe against corrosion at coating voids, or breaks referred to as holidays, cathodic protection current is applied. Effective cathodic protection can reduce the soil-side corrosion rate to a negligible level.* [9]

The effectiveness of the cathodic protection system though can be negatively impacted by pipeline casings.

> *Oil and gas transmission pipelines susceptible to corrosion are regulated to protect the environment and ensure public safety. Cathodic Protection (CP) is the most common technique used to mitigate corrosion and is one of the regulatory requirements in the United States. When pipelines are installed beneath roadways, railroads and other locations, a larger pipe is used to encase the main pipe, i.e., carrier pipe. This arrangement is generally referred as casing. The two pipes in a casing are separated with airgap in-between and end seals are installed to prevent water/soil ingress into the annulus space. When the end seals on the casing are compromised, the threat of corrosion is increased on the cased section of carrier pipe due to ingress of contaminants;*

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[8] Canadian Gas Association: Recommended Practice OCC–1–2013, *Control of External Corrosion on Buried or Submerged Metallic Piping Systems, June 2013, page 1* https://www.cga.ca/wp-content/uploads/2020/12/2013-Canadian-Gas-Association-OCC-1-2013-EN.pdf

[9] Canadian Association of Petroleum Producers: Best Management Practice - Mitigation of External Corrosion on Buried Carbon Steel Pipeline Systems, July/2018 page 5 https://www.capp.ca/wp-content/uploads/2019/11/Mitigation_of_External_Corrosion_on_Buried_Carbon_Steel_Pipeline_Syst-322047.pdf

> *CP is ineffective for the cased section of carrier pipe either due to metallic short or due to electrolytic coupling between the carrier pipe and casing.*[10]

As a result, when the combination of compromised pipeline coating and the effect of the casing are present, the pipeline and casing in the immediate area of the terminus of the casing can corrode at an accelerated rate. As is described in EGI evidence:

> *The excavation was located immediately North of the rail line, West side of St. Laurent. The site was sloping within a drainage area for the rail line. The soil was imperfectly drained and with rock throughout the excavation. Hoe ram activity was required to open the excavation. One girth weld was exposed at this site; note that the photographs show distances measured from the girth weld in both with flow and against flow direction measurements. Coating was removed prior to our arrival.* ***Portions of the casing were found severely corroded on the excavation bank and at the upstream end of the excavation (emphasis added).*** [11]

This evidence of severely corroded casing should inform an experienced utility that the casing contributed to the corrosion on the pipe. Therefore, the type of corrosion is isolated and would NOT lead one to conclude that *"there are other segments of the gas main that exhibit similar pitting/corrosion, due to, for example, field applied coatings or latent third party damage."* **In fact, other segments of pipe would have cathodic protection that would not be impaired by the casing**. To suggest that the corrosion found in the pictures like Figure 4 would be expected in other areas in disingenuous. This analysis is further confirmed that the company did not take further action at the time (2006) beyond repairing/replacing the segment exposed.[12]

Third Party Damage Not Unusual nor a Result of Insufficient Depth

EGI's describes the discovery, assessment and repair of third-party damage to the pipeline.[13] We understand that this type of damage is not unusual and can occur to any pipeline regardless of the vintage of the pipe. This was confirmed by the panel.[14] The panel went on to elaborate that the depth of cover impacts the frequency of occurrence.[15] However, when asked to confirm the depth of cover over the subject pipeline, it was confirmed that it was 2.2m,[16] well in excess of the minimum

[10] **National Association of Corrosion Engineers** (NACE): *Investigations on Cathodic Protection Current Diversion to Carrier Pipe With VCI Gel Annulus Fill in Cased Pipelines.* Sujay Math; Pavan K. Shukla. Paper presented at the CORROSION 2019, Nashville, Tennessee, USA, March 2019. Paper Number: NACE-2019-13133, March 24 2019, page 1 Introduction
[11] Exhibit B, Tab 1, Schedule 1, Attachment 2, page 3
[12] Transcript, Volume 1, March 4, 2022, pages 15, line 19 to page 17, line 6
[13] Exhibit B, Tab 1, Schedule 1, pages 20-23 & Attachments 4 & 5
[14] Transcript, Volume 1, March 4, 2022, pages 18, line 16 to page 19, line 3
[15] Transcript, Volume 1, March 4, 2022, page 19, lines 3-5

[16] Exhibit JT1.3

requirements of the 0.6m by Code and 0.9m by the company.[17] These facts would suggest that depth of cover was not a contributing factor. Very importantly, the damage was found and permanently repaired,[18] and therefore, not impacting the current condition of the pipe.

2016 Bridge Inspection Confirms Corrosion on Anchor Not Pipeline

In this section of evidence, EGI exhibits corrosion on the above ground pipe at the Highway 417 crossing.[19] While above ground pipe can experience a different set of environmental factors, it is also available for visual inspection and remediation of problem areas. The section of evidence infers that a specific concern is corrosion at the anchors which is "*unclear whether the pipeline or anchor sleeves are corroding.*"

> *At this location, the corrosion to the above ground pipeline and/or pipeline anchor could be accelerated due to environmental conditions, such as road salt accumulating around the pipeline and pipeline anchor at ground level.*

However, when asked for more detail from the inspection reports, the company confirmed that the corrosion was on the anchor.[20] This interpretation was confirmed by the witness panel.[21] Again, we highlight another instance where a closer examination of the evidence provides a different perspective upon detailed review.

2017 Depth of Cover Survey does not Present Unmanageable Risk

The company presented findings from a survey to analyze depth of cover issues on its pipeline.[22] In Table 4 of this section, the evidence provided that there are 20 segments of an average length of 14.9m that did not meet the Code requirement of 60 cm of cover. In the preceding paragraph to the Table, EGI provides:

> *Remediation related to depth of cover issues can be completed by relocating the pipeline to a greater depth, or by adding additional cover over top of the pipeline. Additional cover is not a feasible solution with the St. Laurent sections of pipeline as the majority of it is beneath roadway.*

FRPO agrees that this remediation would seem prudent and easily rectifies code compliance, but EGI asserted that this approach is not feasible for St. Laurent as the majority of it is beneath roadway. However, what was not specified and only discovered

[17] Exhibit B, Tab 1, Schedule 1, page 27, para. 40
[18] Transcript, Volume 1, March 4, 2022, page 19, lines 18-28
[19] Exhibit B, Tab 1, Schedule 1, pages 23-25 and Attachment 6
[20] Exhibit I.Ottawa.9, page 1
[21] Transcript, Volume 1, March 4, 2022, page 20, line 1 to page 21, line 1
[22] Exhibit B, Tab 1, Schedule 1, page 25-27 and Attachment 7

through undertaking, is the fact that no section with less than 60 cm of cover is underneath the roadway.[23]

2018 Inspections Result in Routine Pipeline Maintenance

The evidence provides information on another assessment of the pipe in 2018. While much detail is provided, we view this inspection as appropriate assessment in a utility's responsibilities under the Code and approved integrity procedures. The inspecting company provided a summary of recommendations in its report.[24] We asked for the company's summary of those recommendations[25] and received a comprehensive confirming response.[26] To make sure this was not just our interpretation, we sought and received confirmation that these steps were "*not any different than what our requirement is to protect our assets.*" [27]

We note that while the inspections were conducted in Nov of 2018, the version Rev 1.2 is dated February 18, 2021, just ahead of the original filing of the application in early March of 2021. If the Board directs continued assessment of the pipeline condition, it would be informative to understand what was included in the original version of the report and what the company has done in the interim.

St. Laurent Pipeline is Not in Poor Asset Health but Needs Maintenance

As detailed above, while EGI's evidence seems to assert that the pipeline is in poor health, upon closer examination, the issues identified are representative of a vintage steel pipe that requires more regular inspection and maintenance as it ages. This conclusion is consistent with EGI 's own assessment in the Asset Health Index depicted in Figure 17[28] and confirmed by the company in the Technical Conference.[29]

INSUFFICIENT DISCLOSURE ON APPLICATION OF ROBOTIC INSPECTION

Beyond the company's asserted concerns, which we examined in the above section, the application provides EGI's view of their challenges in getting better information about the actual pipeline condition through inline inspection. The company points out that the construction of the St. Laurent line does not allow for the use of traditional inline inspection through the use of a tool known as pig.[30] The application goes on to describe

[23] Exhibit JT1.11A
[24] Exhibit B, Tab 1, Schedule 1, Attachment 8, pages 20-21
[25] Transcript, Volume 1, March 4, 2022, page 21, line 27 to page 22, line 9 and
[26] Transcript, Volume 1, March 4, 2022, page 24, line 3 to page 25 line 8
[27] Transcript, Volume 1, March 4, 2022, page 25, line 9 to page 26, line 3
[28] Exhibit B, Tab 1, Schedule 1, page 42
[29] Transcript, Volume 1, March 4, 2022, page 135, line 19 to page 136, line 21
[30] Exhibit B, Tab 1, Schedule 1, page 35, para. 53

the extraordinary measures that the company would have to undertake just to allow the use of this type of inspection tool.[31] The company concluded that the $30M estimated for these retrofits would not be a prudent investment.

However, what the company did not disclose was their knowledge and consideration of the use of a different technology to obtain insightful information on the pipeline's condition through inline inspection. In response to our request for all internal reports related to EGI's decision to proceed with inspection, three reports were filed. One of the presentations refers to Crawler ILI inspection,[32] which is the first and only evidence of this inspection alternative prior to the technical conference.

Through our research in preparation for the opportunity to ask EGI about this type of inspection, we came to understand that robotic inline inspection is increasing in utilization for North American natural gas utilities to overcome challenges of an "unpiggable" pipeline.[33] In fact, as confirmed by the company, EGI has used the robotic inspection in Mississauga.[34] FRPO attempted to get additional information to assist the Board's understanding of a project of comparable size and length to St. Laurent that was done by Centra Manitoba but the company refused to use its CGA membership to obtain the requested information.[35]

Without that information, we pursued consideration of this robotic technology for the St. Laurent project. The company provided that they considered the use of robotic technology on St. Laurent but chose not to pursue it because of the pipe's location underneath the roadway.[36] However, the company considered using the robotic tool for a 1.2 km stretch that was not underneath the roadway but believed that it would only confirm what they believed and did not believe it would be a prudent expense to investigate as they believe it will just confirm the pipeline's condition.[37]

But, as we provided in our perspective in the previous section, the pipeline is not failing. Further, we believe that it would be worthwhile to invest in assessing the pipeline through the use of the inline inspection for the following reasons:

- In the three years since the company determined that it would not proceed with robotic inline inspection, significant improvements have been made. As an example, the company states that it worked with Rosen in July of 2017 but because the St. Laurent line operated at 275 psig, Rosen's equipment would not work. A quick review of the Rosen website provides many cases studies that demonstrate that pressure limit is no longer a factor.[38]

[31] Exhibit B, Tab 1, Schedule 1, pages 26-39
[32] Exhibit I.FRPO.15 Attachment 2, pages 7-9
[33] KT1.1 FRPO Compendium and Transcript, Volume 1, March 4, 2022, page 33, lines 8-16
[34] Transcript, Volume 1, March 4, 2022, page 33, line 17 to page 34, line 6
[35] Transcript, Volume 1, March 4, 2022, page 35, line 4 to page 37, line 7
[36] Transcript, Volume 1, March 4, 2022, page 40
[37] Transcript, Volume 1, March 4, 2022, page 59, line 16 to page 61, line 1
[38] https://www.rosen-group.com/global/solutions/industry-case-studies/oil-gas/Case-Study-Pushing-the-Minimum-Pressure-Threshold.html

- EGI's parent company, Enbridge Inc. has been developing robotic technology with a partner company for inline inspection which could be applied or modified to be utilized.[39]
- The cost of the actual inline assessment is only $600k.[40] In our view, that is a small investment in determining the general condition of as inline inspection that has not been done prior.

Moreover, FRPO is concerned that another reason why this marginal expense is not being considered stems from the company's pattern of their justification of the replacement of aging infrastructure. This pattern is evidenced directly by the questions answered on the major projects' summary presented to senior management in seeking approval:[41]

> ***Do we have field or failure data and/or Eng. studies to substantiate replacement?***
>
> ***What additional data or work is recommended for decision? (emphasis added)***

If the goal is to find field or failure data to substantiate replacement, robotic inline inspections that do not find areas of concern would not contribute to this purpose. In spite of the summary listing where 2019 Crawler ILI is being listed under the category of additional data or work recommended, EGI decided that it was not a prudent expense.

In our view, it is telling that the company could not produce a signed document wherein senior management sought and received approval from the Enbridge Gas Inc. Board of Directors prior to requesting that the Board of Directors of Enbridge Inc. "*(a) take no exception to, and (b) defer to the Board of Directors of Enbridge Gas Inc. (the "Corporation") with respect to, the approval of the following:*

> *St. Laurent Replacement Project, as revised (the "Project"), including the authority of the Corporation and the officers of the Corporation to take all such action, and to cause the subsidiaries of the Corporation to take all such action, necessary or advisable to effectuate the Project consistent with the project materials provided to the Board (the "Project Memo").*[42]

While this interrogatory asked for "*all internal EGI written communication including reports, emails and memos that relate to the topic of this decision to replace and the*

39 https://www.enbridge.com/Stories/2018/June/Enbridge-NDT-Global-next-generation-crack-inspection-tool-prototype.aspx
40 Exhibit JT1.6, page 3, footnote 2. The estimate essentially doubles when EGI estimates that three integrity digs would be done but the decision on the incremental cost of integrity digs would be made if the inline inspection warranted further direct inspection
41 Exhibit I.FRPO.15, Attachment 2, page 8
42 Exhibit I.FRPO.15, Attachment 3, page 5

timing of the replacement", we did not receive the Project Memo referred to in the above slide. This document may have been helpful to the OEB in this proceeding.

We also asked in the technical conference about written requests for approval[43] and, in the end, were told that "*No additional technical reports or documentation was relied upon by Enbridge Gas for the purposes of forming its decision to proceed with the Project.*"[44] But this specific reference in the slide to the Project Memo, which escaped our notice until preparation of submissions, sounds like the very documentation that we were requesting. We respectfully request that EGI, as part of its Reply Argument, provide the OEB with that Project Memo as an addendum.

In our respectful submission, EGI has not adequately explored the condition of the St Laurent pipeline and should be directed to investigate further the opportunities including the 1.2km section that was originally contemplated.

RISK AND CONSEQUENCES OF FAILURE ARE EXAGGERATED

As noted above and throughout our submissions, we believe that this pipeline's condition should be assessed further as the evidence does not meet EGI's onus to justify the need for $130M replacement. EGI has attempted to assert that the pipe is "*nearing the end of its useful lives and present an unacceptable level of risk of failure and outage to ratepayers and the Company.*"[45] The company makes this claim while referring to its section of prefiled evidence[46] of:

- *several inspection and survey programs:* These programs identified issues that are not representative of the current pipeline as they were isolated or permanently repaired as we have provided in our above section entitled Evidence of Pipeline History Does Not Represent Failing Condition.
- *leak survey history:* EGI did not provide the leak survey history for St. Laurent. While many parties asked about leaks,[47] EGI often provided estimates of future leaks. When asked categorically on pipeline leaks and the categorization of those leaks, EGI provided that there was one pipeline leak due to corrosion.[48]

With the evidence provided on inspections, surveys and leaks, FRPO does see evidentiary support for a pipeline *nearing the end of its useful life*.

Further, we do not agree with the company's statement of *unacceptable level of risk of failure and outage to ratepayers and the Company*. The company has evidenced a scenario where on a design day, a total of 62,000 customers would be lost between EGI

[43] Transcript, Volume 1, March 4, 2022, page 48, line 3 to page 50, line 18 and page 51 lines 1-19
[44] Exhibit JT2.2
[45] Exhibit I.PP.11 a)
[46] Exhibit B, Tab 1, Schedule 1,pages 13-34
[47] STAFF, ED, EP, FRPO, OTTAWA
[48] Exhibit I.FRPO.14

and Gazifere systems and the cost of the outage would be $54M.[49] In spite of the company's unwillingness to provide the study that determined these numbers for our review of assumptions and alternatives,[50] we make the following observations:

- A full 90% of the cost estimate of $54M is made up of $42.8M (plus 15% contingency) of forecasted cost of claims.[51] In spite of limited history,[52] qualification for claims and the appropriateness of those claims would have to be determined based upon the circumstances.
- To estimate customer outages, EGI did a static simulation and not a transient simulation[53] since they deemed it to be an emergency shutoff.[54] This emergency shutoff would be necessary in a situation wherein there was a catastrophic failure.[55] EGI does not have any record of a previous catastrophic failure on a pipeline similar to St. Laurent.[56]

If EGI truly saw a risk of clear and present danger to security of supply to its customers, and to those of its sister company Gazifere, one would anticipate that it would work with Gazifere to run a mock scenario to determine actions that could be considered to mitigate the risk of customer loss. That has not been done.[57]

With these facts, we respectfully submit that the level of risk is NOT *unacceptable.*

EGI RESISTANT TO PROVIDE TECHNICAL INFORMATION IN DISCOVERY

Throughout the proceeding, FRPO has been challenged by the resistance of EGI to provide studies, facts and other evidence to inform our ability to assist the Board. We provide a few examples and the impact.

Simulation Study not Provided

As described in our letters to the Board, we were seeking the results from EGI simulations to understand assumptions made, alternatives considered, mitigation efforts that could be employed.[58] While EGI provided some results of their base

[49] Exhibit B, Tab 1, Schedule 1, pages
[50] FRPO_REQ_COMPLETE RESPONSES_20220225
[51] EGI_IRR_EB-2020-0293_20220222 Exhibit I.FRPO.25, page 3
[52] Exhibit JT1.8
[53] Transcript, Volume 1, March 4, 2022, page 74, lines 5-10
[54] Transcript, Volume 1, March 4, 2022, page 73, lines 21-26
[55] Transcript, Volume 1, March 4, 2022, page 75, lines 9-11
[56] Exhibit JT1.9
[57] Transcript, Volume 1, March 4, 2022, page 75, line 27 to page 77, line 6 and JT1.10
[58] FRPO_REQ EGI_FULSOME RESPONSES_20220106 and FRPO_REQ_COMPLETE RESPONSES_20220225

scenario and legend to interpret station locations just before the Technical conference, without the study and results in a timely fashion, we were unable to prepare additional requests for simulation prior to the Technical conference. Given the time constraints of the conference and other evidence to be tested, we were limited in our ability to assist the Board in this area.

Company Refused to Provide Utility Understanding of Impacts of Casing

As outlined in our review of the pipeline health, FRPO desired to provide the Board with informed perspectives on conditions the evidence provided in support of a pipeline *nearing the end of its useful life.* In the initial stages of the Technical conference, we were attempting to have the witnesses provide the company's understanding of the potential impacts of casing but were refused.[59] Even after Mr. Ladanyi of Energy Probe contributed his experience to assist the witnesses in the relevance of our inquiry, the request was refused.[60] In spite of the company's considered agreement to provide an undertaking detailing some Code history on casings,[61] we were limited on our ability to get the witnesses or company's input of the potential impacts of casings. Since we could not get the company's perspective on potential impacts of casing on cathodic protection and corrosion, we assembled the information from public sources in our above section entitled "**Railway Crossing Pipe is Not Representative of Pipeline Condition".**

Company Would Not Provide Impact of Coatings on Asset Health

At the outset of our discovery in the Technical conference, we sought to have EGI provide its views on pipeline coatings and their impact on asset health. In spite of multiple attempts to get a high-level comparison of pipeline coating on asset health to assist the Board, our request for this comparison was refused.[62]

The company did eventually provide that while both Windsor and London Lines had bare sections in addition to some that were coated as opposed to the St Laurent pipeline that was coated. This highlights one of the main points that were trying to make: both Windsor and London had sections of bare pipe and bare pipe has a greater risk than the coated pipe that is found on the St Laurent pipeline. But as opposed to taking FRPO's views on this, we provide the following from EGI's Asset Management Plan[63].

> *Bare and Unprotected Steel Pipe Replacement Program*
>
> *This program manages the replacement of all bare and unprotected steel mains in the Union rate zones. These mains are more susceptible to leaks as they have*

[59] Transcript, Volume 1, March 4, 2022, pages 11-15
[60] Transcript, Volume 1, March 4, 2022, page 26, line 7 to page 28, line 19
[61] Exhibit JT2.1
[62] Transcript, Volume 1, March 4, 2022, page 4, line 22 to page 9, line 24
[63] EB-2020-0181 Exhibit C, Tab 2, Schedule 1, page 111

> *not been cathodically protected since installation. About 60% of these mains are in urban areas, approximately 5% of which are in highly-developed areas. The remainder are in rural areas. Removing these mains from service will reduce the potential for leaks due to corrosion. Some examples of bare and unprotected failures are shown in Figure 5.2-34. This program was part of the 2020 Customer Survey, where preferences were mixed among Union rate zone customers. More than half of residential customers would prefer that the replacement of bare and unprotected pipes be prioritized, whereas less than half of the contract and non-contract business customers would prefer the work to be prioritized.*

In the above reference, we were left wondering how customers would hold a strong opinion on the removal of bare pipe. The answer is found in the Ipsos survey in the question that was asked:[64]

> *Q8. Today's installation procedures require that all new steel pipelines that are installed are coated and have cathodic protection in place to help prevent leaks and avoid corrosion. The company has some older pipes still in use that are not coated nor protected in this way. Under older rules and regulations these pipes were not required to be coated and protected, however they are more susceptible to corrosion and leaks. The cost to replace these pipes would be over and above the budget set aside for regular ongoing monitoring and inspection and repairs of any leaks found. Replacing all bare and unprotected pipe in the Legacy Union Gas system would increase rates by $1 per year for 10 years. Thinking about the issue of bare and unprotected pipes, which of the following most closely reflects your view?*

We find it disconcerting that the utility would provide their assessment of the impact of lack of pipe coating (i.e., bare pipe) on the susceptibility to corrosion and leaks to customers to gain their support for replacement but the company refused to provide a simple high-level assessment when requested by FRPO to assist the Board by differentiating pipelines by coating.

EGI Would Not and Has Not Produced the Project Memo

Throughout our discovery, we sought written evidence to determine the basis for pursuing the replacement project.[65] We were told that the project was advanced in presentations and was given verbal approval to commence project management process.[66] After consideration, the company provided that "*No additional technical reports or documentation was relied upon by Enbridge Gas for the purposes of*

[64] EB-2020-0181 Exhibit C, Tab 3, Schedule 1, Page 29
[65] Exhibit I.FRPO.15 & FPRO.27 and Transcript, Volume 1, March 4, 2022, page 48, line 3 to page 50, line 18
[66] Exhibit I.FRPO.15, page 2

forming its decision to proceed with the Project".[67] However, as noted above, in preparation of our submissions, we note that the Enbridge Inc. Board gave approval based upon the materials provided in the Project Memo.[68] We cannot understand why this Memo was not provided in spite of our numerous requests for such documentation. We believe that this document should be produced and, once again, request that EGI provide the document as part of its Reply Argument.

In our respectful submission, EGI demonstrated a clear resistance to providing information sought that was not aligned with its objective of receiving approval to replace the pipe. We are concerned that this pattern of behaviour inhibited our ability to be efficient and potentially effective in assisting the Board with understanding of technical matters in the consideration of the St Laurent pipeline.

CONCLUSION

FRPO has described its concerns in the above sections with the summary conclusion:

1) Evidence Of Pipeline History Does Not Represent Failing Condition

Our informed conclusion based upon our assessment of the evidence is that the St. Laurent pipeline is not in poor health but needs maintenance associated with a pipeline of its age and location.

2) Insufficient Disclosure on Application Of Robotic Inspection

In our respectful submission, EGI has not adequately explored the condition of the St Laurent pipeline and should be directed to investigate further the opportunities including the 1.2km section that was originally contemplated.

3) Risk And Consequences of Failure Are Exaggerated

In view of the facts, we respectfully submit that the level of risk associated with maintaining the current pipeline is NOT *unacceptable.*

4) EGI Resistant to Provide Technical Information in Discovery

Our experience of EGI resistance to our obtaining technical evidence to inform the Board on these matters causes concern over why EGI would not want FRPO or the Board to have this information.

In our respectful submission, there is no urgency with pipeline replacement unless one considers the opportunity of obtaining ICM funding. It is interesting to note that ICM does not appear often in the evidence in this proceeding except notably a total of 8 times in the 8 pages of the presentation to Enbridge Inc. Board of Directors.[69] We respectfully submit that ICM funding should not be the prime driver of asset replacement timing.

[67] Exhibit JT2.2
[68] Exhibit I.FRPO.15, Attachment 3, page 5
[69] Exhibit I.FRPO.15, Attachment 3

RELIEF

FRPO urges the Board:

1) to deny the requested Leave to Construct
2) to order additional investigation of pipeline condition including robotic inspection and report back to the Board as part of EGI's 2024 rebasing
3) to produce the Project Memo if not provided by EGI in its Reply Argument

COSTS

In this proceeding, FRPO was assisted by and worked with other parties to develop a shared understanding of the issues and concerns of this project. In spite of challenges with obtaining requested technical information cited above, we strived to provide the Board with published information that would be helpful in assessing the application and determining what is in the public interest. As a result, we respectfully request the award of 100% of our reasonably incurred costs at such time as the Board calls for those costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED ON BEHALF OF FRPO,

Dwayne Q

Digitally signed by R. Dwayne Quinn
DN: cn=R. Dwayne Quinn, o=DR QUINN & ASSOCIATES LTD., ou=PRINCIPAL, email=drquinn@rogers.com, c=CA
Date: 2022.03.21 18:23:37 -04'00'

Dwayne R. Quinn
Principal
DR QUINN & ASSOCIATES LTD.